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The State of South Carolina
Department of Consumer Affairs

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Brandolyn Thomas Pinkston
Administrator

ACCEPTED
Legal 12-2-04

December 1, 2004

S.C. PUBLIC SERVICE COMMISSION
RECEIVED
DEC 02 2004
EXECUTIVE DIRECTOR'S OFFICE

Honorable Charles Terreni
Interim Executive Director
South Carolina Public Service Commission
P.O. Drawer 11649
Columbia, SC 29211

RE: South Carolina Electric & Gas Company
Docket No. 2004-178-E

Dear Mr. Terreni:

Enclosed for filing please find the original and ten copies of the **Consumer Advocate's Proposed Order** in the above referenced proceeding.

Sincerely,

Hana Pokorna-Williamson

Hana Pokorna-Williamson
Staff Attorney

cc: parties of record

CERTIFICATE OF SERVICE

This is to certify that I, Hana Pokorna-Williamson on behalf of Elliott F. Elam, Jr., Acting Consumer Advocate, have served this day the foregoing **Proposed Order** upon the Executive Director of the Commission by fax and first class mail and on the persons named below, at the addresses set forth, by first class mail and electronic mail

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Columbia, South Carolina
December 1, 2004

STATE OF SOUTH CAROLINA

BEFORE THE PUBLIC SERVICE COMMISSION

DOCKET NO. 2004-178-E

IN THE MATTER OF:)
)
South Carolina Electric & Gas Company)
Application for Adjustment in the Company's)
Electric Rate Schedules and Tariffs)
)

Proposed Order
of
Consumer Advocate

Elliott F. Elam, Jr.
Hana Pokorna-Williamson
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3600 Forest Drive
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December 1, 2004

I.

INTRODUCTION

This matter is before the Public Service Commission of South Carolina (the Commission) on the Application of South Carolina Electric & Gas Company (SCE&G or the Company), filed July 1, 2004, for adjustments in the Company's electric rates and tariffs and for certain changes in the Company's General Terms and Conditions for Service. The Application was filed pursuant to S.C. Code Ann. §§ 58-27-820, 870 (1976, as amended) and S.C. Code Regs. 103-834 (as amended (South Carolina Public Service Commission Rules of Practice and Procedure).

The Company's rates and tariffs were approved by the Commission in Order No. 2003-38, issued January 31, 2003, in Docket No. 2002-223-E. In that order, the Commission authorized a net increase in operating revenues of $70,704,000 and allowed a return on common equity of 12.45%. The rates and tariffs as requested in the Company's Application in the present docket would produce an increase in annual revenues of approximately $81 million and provide a return on common equity of 11.75%, according to the Company's calculations.

At the beginning of the hearing, the Company informed the Commission that it entered into stipulations and settlements with the Commission Staff, SMI, Wal-Mart and SCEUC. All stipulating parties agreed to an increase in the Company's electric rates of $51,149,000 which would result in a total increase of approximately 3.57% on electric retail revenue measured against the adjusted test year. All stipulating parties further agreed that Return on Common Equity should be in a range of 10.4% to 11.4% and that for setting rates the mid point of 10.9% should be used. In addition, the stipulation between the Company and the Commission Staff addressed a number of additional items contained in the Company's Application pertaining to the capital structure, inclusion of the Jasper plant in the Company's rate base, fixed pipeline capacity charges, recovery of the Saluda dam Remediation project, a number of accounting adjustments, new depreciation rates, accelerated capital recovery mechanism for the Cope Generating Station, cost of service study, basic facility charges, reconnection charges, new economic Interruptible Service Rider and certain issues pertaining to customer deposits. SCEUC and the Company also agreed in their stipulation that the Company would withdraw its requests for a new Economic Interruptible Service Rider and changes in customer deposit requirements. These two parties further agreed that the resulting rate increase for Large general Service class will be 1.256%. All stipulating parties stated that the stipulations are based on the result reached and are in no way severable as to specific issues or matters contained therein.

II.

FINDINGS OF FACT

Based upon the Application, the testimony and exhibits received into evidence at the hearing and the entire record of these proceedings, the Commission makes the following findings of fact:

Rate of Return

* The capital structure utilized by the Commission in this proceeding for the determination of the fair overall rate of return is the capital structure of South Carolina Electric & Gas, updated to August 31, 2004. This consists of 46.96% long-term debt, 2.73% preferred stock, and 50.31% common equity.

* The embedded cost rate for long-term debt of 6.56% and the embedded cost rate for preferred stock of 6.40% as of August 31, 2004 have been used in the determination of the fair overall rate of return approved herein.

* The fair rate of return on common equity which SCE&G should be allowed the reasonable opportunity to earn is 10.0%, which is the rate of return adopted by the Commission for this proceeding. The capital structure and cost of capital which the Commission has approved herein produce an overall rate of return of 8.28% for SCE&G retail electric operations as depicted in the following table:

TABLE A

COMPONENT OF CAPITAL STRUCTURE	RATIO %	EMBEDDED COST/RATE %	OVERALL COST/RATE %
Long Term Debt	46.96	6.56	3.08
Preferred Stock	2.73	6.40	0.17
Common Equity	50.31	10.00	5.03
	100.00		8.28

EVIDENCE AND CONCLUSIONS

EVIDENCE AND CONCLUSIONS REGARDING COST OF CAPITAL COST OF EQUITY

Legal Standards

In setting rates, the Commission must determine a fair rate of return that the utility should be allowed the opportunity to earn after recovery of the expenses of utility operations. The legal standards applicable to this determination are set forth in *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 602-03 (1944) and *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-73 (1923). These standards were adopted by the South Carolina Supreme Court in *Southern Bell Telephone and Telegraph Co. v. South Carolina Public Service Commission*, 244 S.E. 2d. 278, 281 (S.C. 1978). Specifically, *Bluefield* holds that:

> What annual rate will constitute just compensation depends upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting the opportunities for investment, the money market and business conditions generally.

Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. at 692-73, as quoted in *Southern Bell Telephone and Telegraph co. v. South Carolina Public Service Commission*, 244 S.E. 2d. at 281. In addition, these cases establish that the process of determining rates of return requires the exercise of informed judgment by the Commission. As the South Carolina Supreme Court has held, quoting *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. at 602-03:

> the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its ratemaking function, moreover, involves the making of 'pragmatic adjustments'. . . . Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling. . . . The ratemaking process under the Act, i.e., the fixing of 'just and reasonable' rates, involves the balancing of the investor and the consumer interests.

Southern Bell Telephone and Telegraph Co. v. South Carolina Public Service Commission, 244 S.E. 2d. at 281. This is in keeping with the general rule that "[r]atemaking is not an exact science, but a legislative function involving many questions of judgment and discretion." *Parker v. South Carolina Pub. Service Commission*, 313 S.E.2d 290, 291 (S.C. 1984). These principals have been employed by the Commission and the Courts of this State consistently since their adoption in 1978. They continue to provide the appropriate standards to guide the Commission's determination of rates of return in proceedings such as this one. From these authorities, the Commission derives the following specific points to guide its evaluation of the evidence in this case:

(1) The rate of return should be sufficient to allow SCE&G the opportunity to earn a return equal to firms facing similar risks;

(2) The rate of return should be adequate to assure investors of the financial soundness of the utility and to support the utility's credit and ability to raise capital needed for on-going utility operations at reasonable cost;

(3) The rate of return should be determined with due regard for the present business and capital market conditions facing the utility;

(4) The rate of return is not formula-based but requires an informed expert judgment by the Commission balancing the interests of shareholders and customers.

Finally, the Commission notes that "[t]he determination of a fair rate of return must be documented fully in its findings of fact and based exclusively on reliable, probative, and substantial evidence on the whole record." *Porter v. South Carolina Public Service Commission,* 504 S.E.2d 320, 323 (S.C. 1998) citing *S.C. Code Ann.* § 58-5-240 (Supp. 2003); accord S.C. Ann. § 58-27-870(G) (Supp. 2003).

OVERVIEW OF THE TESTIMONY

The starting point for the determination of SCE&G's cost of capital is a review of the testimony of the witnesses who used financial models to measure required equity returns numerically. Four witnesses testified as to the appropriate cost of capital for SCE&G based on the use of financial models. Those witnesses were:

- Burton G. Malkiel, Ph.D., the Chemical Bank Chairman's Professor of Economics at Princeton University who testified on behalf of SCE&G. Dr. Malkiel is former Chairman of the Economics Department of Princeton, former Dean of the Yale Business School, and a former member of the President's Council of Economic Advisors. He is a member of the Board of Directors and Chairman of the Investment Committee of Prudential Securities Company and is a Member of the Board of Directors of Vanguard Group of Investment Companies. Dr. Malkiel has published extensively on finance issues both in the academic and popular press;
- Glenn A. Watkins, MBA, Executive Vice-President and Senior Economist, with Technical Associates, Inc. who testified on behalf of the Consumer Advocate;
- Kevin W. O'Donnell, CFA, President of Nova Energy Consultants, Inc. who testified on behalf of the South Carolina Energy Users Committee; and
- Labros E. Pilalis, MPA-JD, a consultant with Rhoads and Sinon Group LLC, who testified on behalf of the Commission Staff.

In addition, Thomas R. Osborne, Managing Director in the Global Energy and Power Group of UBS Warburg, LLC's Investment Banking Department, testified on behalf of SCE&G concerning conditions in national capital markets and the group of comparable companies he selected and provided to Dr. Malkiel as an input to Dr. Malkiel's calculations. Julie M. Cannell, President of J.M. Cannell, Inc. testified on behalf of SCE&G concerning investors expectations for the return on equity in this proceeding. Finally, Kevin Marsh, SCE&G's Senior Vice President and Chief Financial Officer, testified on the present business and market conditions that the Company is facing.

Dr. Malkiel based the recommendations in his testimony on the Discounted Cash Flow (DCF) methodology, as well as on policy arguments as to why this Commission should look to the Company's currently approved rate of return on equity of 12.45%, which was approved in its last rate case two years ago, as a top of a range of possible returns on equity in this case. The other three witnesses also performed a DCF analysis, and Mr. Watkins and Mr. Pilalis also used the Capital Asset Pricing Model as a means to estimate the return on equity for SCE&G.

REVIEW OF THE METHODOLOGIES

Capital Asset Pricing Model ("CAPM")

Two of the four witnesses, Mr. Watkins and Mr. Pilalis, performed a CAPM analysis as one of their tools to measure the Company's cost of equity capital. Unlike the results in the Company's last rate case in 2002, the CAPM model produced the higher rates of return of the two methodologies used in this case. Mr. Watkins's CAPM analysis produced a return of 9.90% to 10.20% while Mr. Pilalis' produced a return of 10.35% to 10.74%. In our Order No. 2003-38 in the Company's 2002 rate case, we found that the evidence on the record demonstrated that, in the present economic conditions, the CAPM model does not accurately measure the required rates of return for companies like SCE&G. Order No. 2003-38 at 55. In addition, we held that:

> The Commission also finds credible the testimony of Dr. Malkiel that the empirical evidence and research raises questions concerning the theoretical assumptions underlying the CAPM model. The CAPM model employs a measure of a stock's volatility relative to the broader market, called beta. On the basis of the beta, the CAPM model attempts to calculate the company's risk and market's required return for taking on that risk. The validity of beta as an indicator of required return is at the heart of the CAPM model. Recent research, however, has shown that betas are not

> stable, and they cannot be accurately measured. More importantly, a number of recent and important studies in the finance literature have shown that beta and return are essentially uncorrelated.

Order No. 2003-38 at 56 (citations omitted).

Although two witnesses chose to perform CAPM analyses in this case, the theory and assumptions underlying the CAPM methodology have not changed since that Order was issued in January 2003. Tr. Vol. 3 at 924. No witness in this proceeding has addressed our concerns with the CAPM methodology set forth in Order No. 2003-38. Therefore, there is no reliable, probative and substantial evidence in the record of the current proceeding which would lead us to change our view in this case. Indeed, Dr. Malkiel has not changed his opinion on the validity of the CAPM methodology. Tr. Vol. 2 at 507. Therefore, the Commission finds that CAPM is not a reliable basis for measuring return in this proceeding. Again, as in our prior Order, the Commission notes that this decision is based on the record before it in this proceeding, and does not foreclose parties from advancing testimony using CAPM in future cases, or from addressing the concerns raised about this analytical tool in future dockets.

Discounted Cash Flow Model ("DCF")

The discounted cash flow (DCF) model is perhaps the most commonly used model for estimating the cost of common equity for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows. When applied to common stocks, the dividend discount model describes the value of a stock as follows:

$$P = \frac{D_1}{(1+K_1)} + \frac{D_2}{(1+K_2)^2} + \ldots + \frac{D_n}{(1+K_n)^n} = \sum_{i=1}^{n} \frac{D}{(1+K)^n}$$

where: P = current price

D_1 = dividends paid in period 1, etc.

K_1 = discount rate in period 1, etc.

n = infinity

This relationship can be simplified if dividends are assumed to grow at a constant rate of "g". This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework, the price of a stock is determined as follows:

$$P = \frac{D}{(K - g)}$$

where: P = current price

D = current dividend rate

K = discount rate (cost of common equity)

g = constant rate of expected growth

This equation can be solved for K (i.e., the cost of common equity) to yield the following formula:

$$K = \frac{D}{P} + g$$

This formula essentially states that the return expected or required by investors is comprised of two factors: the yield (current income) and expected growth (future income).

All four cost of capital witnesses in this case used the DCF model to estimate SCE&G's cost of equity capital. Dr. Malkiel employed a single DCF calculation based on the assumptions that he found most reasonable and accurate. Based on his calculations using the group of comparable companies provided to him by SCE&G witness Osborne, Dr. Malkiel testified to a single point recommendation for DCF of 10.0%. Tr. Vol. 2 at 461-463.

Mr. Watkins provided two different calculations of DCF, one using both historical and prospective growth rates, and the other method employing only forecasted or prospective growth rates, which was the method preferred by this Commission in the Company's last rate case in 2002. Order No. 2003-38 at 64-65. Using the mix of historical and prospective growth rates, Mr. Watkins determined that an appropriate DCF range for SCE&G of 8.7% to 9.4%. Tr. Vol. 3 at 933. Using exclusively prospective growth rates, Mr. Watkins recommended DCF range was 8.6% to 9.2%. Tr. Vol. 3 at 939-940. In both instances, Mr. Watkins concurred in the use of the comparable companies used by Dr. Malkiel and provided by Mr. Osborne. Tr. Vol. 3 at 925.

Mr. O'Donnell also employed the DCF in his estimation of the appropriate cost of capital for SCE&G. Unlike the other witnesses, Mr. O'Donnell used a different group of comparable companies than those chosen by SCE&G witness Osborne. All of the 25 companies in Mr. O'Donnell's comparable group are listed in The Value Line Investment Survey "Electric Utility Industry" group. They are also involved in the natural gas business and are subject in varying degrees to the same federal laws, similar regulatory benefits and constraints, capital requirements, and competitive forces as SCE&G. Tr. Vol. 4 at 1230. Mr. O'Donnell's selection criteria was also based on companies with S&P stock ratings similar to SCANA (A-, B+, or B), and positive dividends with no recent reductions in dividend payment. *Id.* Mr. O'Donnell's analysis produced a DCF range for his comparable companies of 8.50% to 9.50%. He also conducted a DCF analysis for SCANA Corporation, SCE&G's parent company, which indicated a DCF of 10.0%. Tr. Vol. 4 at 1234. Based on these figures, Mr. O'Donnell's recommended that SCE&G be granted a rate of return on equity of 10.0%. Tr. Vol. 4 at 1235.

Finally, Mr. Pilalis' also used the DCF methodology based on the group of comparable companies developed by Mr. Osborne, except that he also included SCANA Corporation in his calculations. His analysis produced a DCF range of 9.07% to 9.36%. He initially averaged the DCF cost of common equity estimates of the six enterprises that are members of the proxy group of companies. This produced an average cost of common equity of 9.36%. He then averaged this figure with his determination of SCANA's stand-alone DCF cost of common equity capital of 9.07%. Therefore, his recommended DCF number was 9.21%. Tr. Vol. 5 at 1484.

The following table summarizes the DCF recommendations of the witnesses in this case: DCF study results and recommendation.

Witness	Low End	High End	Recommended DCF
Malkiel	--	--	10.00% [1/]
Pilalis	9.07%	9.36%	9.21% [2/]
O'Donnell	8.50%	10.0%	10.00% [3/]
Watkins:			
Recommended	8.70%	9.40%	9.10% [4/]
Alternative	8.60%	9.20%	------- [5/]

Dividend Yield

Each of the witnesses used a somewhat different time period to estimate the dividend yield component of the DCF model. While Dr. Malkiel used a single day's spot price, Mr. Pilalis used the average monthly dividend yields during the most recent 12-month period. Tr. Vol. 5 at 1480. Mr. Watkins employed the three-month average June - August 2004. Tr. Vol. 3 at 928. Finally, Mr. O'Donnell averaged the dividend yields expected over the next 122 months for 26-week, 13-week, and 4-week time periods. Tr. Vol. 4 at 1230-1231. With respect to the time period considered in determining a proper dividend yield, this Commission finds that a reasonably recent time period

1/ Before flotation cost adjustment. Dr. Malkiel did not offer a DCF cost of equity range.

2/ Direct at 12.

3/ Direct at 16.

4/ Direct at 23.

5/ Mr. Watkins conducted an alternative DCF analysis that considered only forecasted earnings per share (FPS) estimates consistent with this Commission's findings in Order No. 2003-83 at 65.

should be considered. The time period should be long enough to smooth any random daily stock price oscillations, yet short and recent enough tor reflect current investor expectations.

Dr. Malkiel and Mr. Watkins used somewhat different techniques to develop and adjusted dividend yield.[6/] Whereas Dr. Malkiel escalated the current dividend per share (D_0) by 1 + growth, Mr. Watkins escalated D_0 by 1 + 0.5 growth. Mr. Watkins explained that this difference rests on the analysts assumption of when the next dividend increase will occur. Tr. Vol. 3 at 228-929. Mr. Watkins concluded that the impact on DCF results using this method or the method used by Dr. Malkiel is immaterial, as there is a total DCF difference of about 10 basis points between the two methods. Given the small difference in total DCF results using the two methods to determine an adjusted dividend yield this Commission expresses no preference to either technique, but is aware that the Watkins method produces DCF results about 10 basis points lower than the Malkiel method.

Growth Rates

Growth, as represented by G in the DCF model tends to be the most controversial element of the methodology as there is no one accepted method used by analysts or investors to project expected growth in dividend payments. Moreover, there are a myriad of sources available that provide historical and forecasted growth rates for individual companies.

Dr. Malkiel considered only forecasted earning per share (EPS) growth rate published by FirstCall and I/B/E/S. Mr. Pilalis used also forecasted EPS but relied upon forecasts provided by

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6/ Adjusted dividend yield relates to the dividend expected to be paid one year from the Present (D). It is the raw, or current dividend (D_0) escalated to reflect growth in dividends during the upcoming year.

Value Line, Yahoo Finance and Charles Schwab. Tr. Vol. 5 at 1481. Mr. Watkins conducted two different DCF analyses: his recommended approach that considers historical and forecasted growth rates; and an alternative analysis that only considers forecasted EPS growth. Mr. Watkins' historical growth rate analysis is based on retention (or plowback) growth and EPS growth as reported by Value Line. Tr. Vol. 3 at 932. Mr. Watkins prospective growth analysis considered forecasted retention growth, EPS and DPS growth as published by Value Line, and forecasted EPS published by IBES/FirstCall. *Id.* at 933. Mr. O'Donnell also considered historical and forecasted growth rates in his DCF analysis. Mr. O'Donnell's analysis included: historical plowback (retention) growth; historical EPS, DPS and book value per share; Value Line forecasted EPS, DPS and book value per share; and, forecasted EPS reported by Charles Schwab & Co. Tr. Vol. 4 at 1232.

Historical vs. Forecasted Growth

Although the DCF model requires the use of forward looking (future) growth, analysts and the investment community use different methods and techniques to estimate future growth. Although forecasted growth rates are estimates of expected growth in the future, this Commission finds persuasive the testimony of Mr. Watkins that investors consider a multitude of methods in evaluating growth and that due to recent events surrounding the credibility of stock analysts forecasting, all investors do not rely exclusively on these estimates.

This Commission finds that forecasted growth rates more accurately comport with the DCF model requirements. This is consistent with our precedent set forth in the Company's last rate case order. Order No. 2003-38 at 64-65. However, sole reliance should not be given to stock analysts forecasts particularly in view of the recent controversies surrounding the credibility of this forecasts. We also agree with Mr. Watkins' testimony that, with respect to fixed regulated utilities, historical growth can be a reasonable barometer of future growth and should be considered on a case by case basis. Tr. Vol. 3 at 932. In this regard, this Commission finds that historical growth can and does provide at least a check on the reasonableness of a company's forecasted growth.

Comparable Companies

Because SCE&G is not a publicly traded company, a DCF analysis requires the selection of a group of companies that a witness believes are comparable to SCE&G. SCE&G witness Thomas Osborne conducted a study of energy utilities whose size and risks are similar to SCANA. Mr. Osborne developed a list of six companies that he deemed an appropriate peer group for evaluating SCE&G risks and cost of common equity. Mr. Pilalis and Mr. Watkins accepted Mr. Osborne's peer group. Mr. O'Donnell developed a peer group that consists of 25 companies. Mr. O'Donnell selection criteria was based on companies with: electric and natural gas operations; S&P stock ratings similar to SCANA (A-, B+, or B); and positive dividends with no recent reductions in dividend payment. Tr. Vol. 4 at 1230.

There was little to no controversy regarding the Osborne or O'Donnell peer groups, since Mr. O'Donnell's DCF analysis produced similar results to those obtained by witnesses using the Osborne peer group. As such, this Commission finds no need to render an opinion as to whether the Osborne or O'Donnell peer groups more accurately represent the risks confronted by SCE&G. However, we note that SCE&G witness Malkiel did not consider SCE&G's parent, SCANA in his cost of equity analysis. Mssrs. Pilalis, Watkins and O'Donnell considered a peer group as well as SCANA specifically in their respective cost of equity analysis. This Commission agrees that absent any compelling reasons to the contrary, SCANA should be specifically considered in conducting cost of equity studies applicable to SCE&G.

DR. MALKIEL's ADDITIONAL REASONS TO INCREASE THE APPROVED RETURN ON EQUITY

In his testimony in this case, Dr. Malkiel also offered additional reasons beyond his DCF analysis for consideration in setting an approved rate of return on equity for SCE&G. In summary, Dr. Malkiel provided two reasons why this Commission should maintain the 12.45% rate of return on equity that it allowed in 2002. The first reason is the assertion that today's interest rates are unusually low and that as the Federal Reserve increases the Federal Funds interest rate, required rates of return for all assets are likely to rise. Tr. Vol. 2 at 469. Dr. Malkiel also stated his DCF analysis conducted for this case is lower because 10-year Treasury interest rates are currently about one percentage point lower than during 2002. *Id.* at 467. He then reasoned that as the Federal Reserve eases its "very aggressive easy money policy" and raises its short-term Federal Funds interest rate, that all capital costs will likely rise as well. However, Dr. Malkiel's opinion as to the movement of longer term interest rates is speculative and does not agree with the facts set forth in the testimony in this case. Specifically, Mr. Watkins compared actual recent 10-year Treasury interest rates with those actually in effect during 2002 and found that 10-year treasury interest rates are actually marginally higher <u>now</u> than they were in 2002 at the time of the Company's last rate case. Tr. Vol. 3 at 951-954. Mr. Watkins comparison of 2002 and 2004 interest rates are based on actual data and is unrefuted. More importantly, however, is the analysis conducted by Mr. Watkins that compares the reaction of the investment community as the Federal Reserve increased the Federal Funds rate three times this year. As shown in his analysis, Mr. Watkins observed that even though the Federal Reserve has increased the Federal Funds rate three times from 1.00% in June 2004 to 1.75% as of September 21, 2004, long-term U.S. Treasury interest rates have actually decreased since that time. *Id.* At 953. Mr. Watkins' observations of recent decreasing long-term interest rate trends compared to increases in the short-term Federal Funds rate are convincing. Furthermore, Dr. Malkiel's supposition that current capital costs will likely rise as a result of future Federal Reserve actions is not supported by the evidence in this case.

The second reason Dr. Malkiel provides for maintaining the current authorized return on common equity of 12.45% is that SCE&G made "considerable investments (such as the Jasper plant) during earlier periods when required rates of return on equity were higher". Dr. Malkiel then concludes "It is reasonable to allow the company to recover those costs at return rates that more closely approximate the cost of capital during the development of this new plant". Tr. Vol. 2 at 469-470. This opinion of Dr. Malkiel requires no detailed discussion. As noted by Mr.Watkins, it is a most basic financial and economic concept that capital costs are forward-looking. Tr. Vol. 3 at 955. Dr. Malkiel's opinion is also clearly at odds with the seminal Bluefield Water Works v. Public Service Commission of West Virginia opinion (262 U.S. 679) which provides:

> "What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in

> the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties;
>
> • • •
>
> A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.

Therefore, for the reasons set forth above, Dr. Malkiel's recommendation that consideration be given to the rate of return on common equity authorized in our Order No. 2003-38 is rejected.

FLOTATION ADJUSTMENT

A flotation adjustment is an upward adjustment to the cost of capital to reflect the cost of issuing, or "floating," new capital. The adjustment reflects (a) the fact that flotation of new capital incurs substantial cost and (b) as an accounting matter, those costs are not otherwise recovered in rates. In his testimony in this case, Dr. Malkiel has advocated a flotation adjustment of roughly 50 basis points be added to the cost of equity for SCE&G. Tr. Vol. 2 at 463-466. Mr. Watkins and Mr. Palalis recommended no addition for flotation costs, and Mr. O'Donnell did not address the issue in his testimony.

This Commission has been consistent in its treatment of the issuance cost adjustment for several years. It has considered the need for an adjustment on a case-by-case basis. It has adopted an adjustment is those cases where the involved company was able to provide evidence that it recently or in the near term future raised or would raise common equity in the market, the proceeds of which would benefit the ratepayers of South Carolina. This approach to flotation cost adjustments is sound and reasonable. First, one reason for making such an adjustment is to protect existing shareholders from dilution of the book value of their holdings which would result if a company were forced to issue additional common equity at below book value. However, as demonstrated in the testimony of Mr. Watkins, SCANA's stock has been selling well above book value. Tr. Vol. 3 at 943-944. If the Company were to issue additional common stock, it more than likely would have the effect of increasing, not decreasing, the book value of existing shares. A second reason that is often cited as a need for an adjustment is to compensate shareholders for expenses incurred in the issuance of common stock in the past. As shown in the testimony of Mr. Watkins, the expenses associated with the Company's last stock issuance have been more than adequately recovered by the flotation costs adjustment approved by this Commission in the Company's last rate case in 2002. Tr. Vol. 3 at 946-948. A purpose of regulation is to permit the recovery of legitimately incurred expenses. Dr. Malkiel's proposal would permit the recovery of expenses not incurred. Therefore, the Commission finds that the evidence in this case does not support flotation cost adjustment.

ESTABLISHMENT OF A COST OF EQUITY CAPITAL

Determining the appropriate return on equity is more than a numerical calculation. Many factors must be considered when deriving the appropriate return. We are guided by the principles as set forth in the *Hope* and *Bluefield* cases, as well as the statutory mandate set forth in S.C. Code Ann. § 58-27-870(G) which requires our determination of a fair rate of return to be documented fully in the findings of fact and based exclusively on reliable, probative and substantial evidence on the whole record. Based on our evaluation of the evidence in this case, we have determined that the Commission will use the testimony contained in the witnesses' DCF analyses as the basis of our finding in this case. Unlike some other cases that have come before this Commission in the past, there is a remarkable level of agreement among the four witnesses as to the proper DCF figure. These recommendations run from a low of 9.1% set forth by Mr. Watkins, and the 9.88% as set forth by Mr. Palalis, to the 10.0% figure espoused by Mr. O'Donnell and Dr. Malkiel. The Commission is convinced that the most prudent, just and reasonable response to the financial evidence, to present business and market conditions, and to the interrelated interests of the Company and its customers, is to set a rate of return for the utility at high end of this range. Accordingly, we adopt a return on equity in this case for SCE&G of 10.0%, with no provision for flotation costs. The Commission finds that this return on equity should provide the Company an opportunity, with sound management, to retain its access to capital on reasonable terms and to support and maintain its credit. Setting a return on equity capital at this level should indicate to investors and potential investors in SCE&G that their continued investment in the electric and gas infrastructure on which this State depends will be treated fairly by this Commission, and that their reasonable return expectations will be respected. The Commission believes that this rate of return properly balances the interests of investors and customers and furthers the long term interests of both groups by helping the Company maintain its debt rating and thereby reduce its long term cost of debt service.

CAPITAL STRUCTURE

In keeping with established Commission practice, the Staff has updated the Company's capital structure and cost of debt and preferred stock, to reflect the figures current at the time of the Staff's recent audit. These underlying figures are not in dispute. Dr. Malkiel recommended a capital structure consisting of long-term debt, preferred stock, and common equity. Initially, Mr. Watkins recommended that the Commission should depart from its long-standing practice of setting cost of capital based on long-term obligations, and proposed that the Commission insert into the cost of capital analysis consideration of the Company's short-term debt. However, after reviewing the rebuttal testimony of SCE&G witness Marsh, Mr. Watkins stated that he was withdrawing his recommendation as to the inclusion of short term debt in the capital structure. Tr. Vol. 3 at 992-993.

EMBEDDED COST RATE OF LONG-TERM DEBT AND PREFERRED STOCK

The Commission's determination concerning the amount and cost of long-term debt and preferred stock is based on the embedded rates of those instruments as shown in the Company's books and records. The rates used are the actual rates in force on September 30, 2002, determined subject to the Staff audit of the Company's books and records.

EVIDENCE AND CONCLUSIONS CONCERNING

REVENUES, EXPENSES AND INCOME

(FINDINGS OF FACT NOS. X-XX)

ANNUALIZATION OF NCEMC CONTRACTS (ADJUSTMENT NO. 1)

In adjustment No. 1, SCE&G proposes to annualize the revenues associated with two new contracts for sale of capacity and energy to the North Carolina Electric Membership Corporation (NCEMC). These sales are made under two separate contracts, one for 100 MW for a term of two years and one for 250 MW for a term of nine years. According to the Company witness Walker, both contracts involve sales of capacity and energy from SCE&G's general system supply and went into force during January of 2004. The effect of this adjustment is to increase test year non-fuel revenue by $30,099,357. Walker direct testimony at 9 and 10.

Mr. Watkins, testifying on behalf of the Consumer Advocate, shed more light on the circumstances of these contracts. He explained that each of these contracts generated fixed capacity revenue that do not vary by month and variable energy margins that depend on the kwh purchased. Because only three months of experience (January through March) is reflected in the test year revenue, Mr. Watkins agreed with the Company that it would be appropriate to annualize this revenue for ratemaking purposes. While he had no disagreement with annualized fixed charges, he disagreed with the Company's annualization of energy margins from these two contracts. For example, with respect to the energy margins from the 250MW contract, actual margins booked for three months in the test year were $1,047,601. Ms. Walker then used the actual margins for April and most of May 2004, which were negative $737,033. For the remaining months of June through December Ms. Walker then assumed a zero margin on energy. Transcript Vol. 3 at 957. Mr. Watkins disagreed because the energy charge actually billed to NCEMC on both contracts is based on a hypothetical energy cost and that the Company claimed the intent is for the energy margins to eventually zero out. He further stated that there is no way to evaluate this probability. More importantly, however, he testified that the margin actually earned to date has been significantly positive. *Id.*, at 948.. When he annualized the actually energy margins billed for the first six months of the contract (January through June), his annualization resulted in an additional energy margin of $618,689 during the July through December period. *Id.* As shown in his Schedule 10, Hearing Exhibit 23, this additional margin coupled with the actual margin during July through June period yields a test year adjustment of $189,777. Using the same method, his energy margin annualization for the 100 MW contract resulted in a test year adjustment of $4,326,579 as compared to Ms. Walker's adjustment of $4,253,682. *Id.* On a retail basis, the net effect of his adjustments for both contracts is to increase revenues by $931,000 more than those proposed by Ms. Walker. *Id.* at 49.

In her rebuttal testimony, Ms. Walker reiterated the zero margin intent and referred to more recent margin revenues from the 100 MW contract stating that those revenues dropped substantially below the level on which the pro forma adjustment was based. Walker rebuttal testimony at 4. In response to Ms. Walker's rebuttal, Mr. Watkins invited Ms. Walker to update his annualization based on the most recent current information available. Watkins surrebuttal at 7. The record does not reflect that any more recent data has been introduced by the Company.

The record shows that the Company's proposed adjustment is based on a presumption that may or may not occur; namely, that the energy component of both contracts will eventually zero out. However, there is no evidence before us that they will actually do so. This is partially due to the fact acknowledged by Mr. Watkins that since both contracts are new, historical patterns are not yet available. Watkins surrebuttal testimony at 7. Mr. Watkins' annualization of the actual energy margins which is based on the Company's responses to Staff Data Request 1-62, paints a more accurate picture than the thee months (January through March) reflected in the test year revenue. To the extent that more recent data would produce another result, the Company did not introduce any more recent data as evidence. Therefore, the Commission accepts and adopts the Consumer Advocate's adjustment.

PURCHASED POWER SETTLEMENT COSTS ADJUSTMENT NO.2)

The Company's proposed adjustment No. 2 (Amortize Unrecovered Fuel Component of Purchased Power) adjusts expenses to amortize over three years the fuel component of purchased power that has not been recovered through the fuel adjustment clause in accordance with the stipulation approved by the Commission in Docket No. 2004-02-E. This adjustment would increase test year expenses related to purchased power by $8,539,354 (Walker direct at 10, lines 3-8).

As stated in the direct testimony of Mr. Watkins (Tr. Vol. 3 at 959-960) and further evidenced by the record in the 2002 and 2003 SCE&G fuel dockets (Docket Nos. 2002-2-E and 2003-2-E), from March 2001 through February 2003, SCE&G collected from ratepayers all purchased power costs through the fuel clause mechanism. However, the fuel clause statute in effect at that time only allowed recovery of fuel costs used in the Company's own generation.[7] The Consumer Advocate appealed this allowance of total purchased power costs within the fuel clause and the Circuit Court reversed the allowed treatment and remanded the matter to the Commission. Subsequent to the Circuit Court's ruling, SCE&G and the Consumer Advocate entered into a stipulation whereby the parties agreed to allow recovery from ratepayers of the imputed non-fuel component of purchased power costs over time. The non-fuel component was stipulated to be 40% purchased power costs and totaled $25,618 million for the two years in question. In the 2004 fuel case, under the terms of the stipulation, SCE&G's deferred fuel cost recovery balance was reduced by the $25.618 million and the parties agreed to allow re-recovery of this amount, over some period of time through base rates. The parties agreed to disagree on the time period (amortization period) in which this $25.618 million should be re-collected. In this proceeding, SCE&G proposed a three-year amortization period arguing that the three-year period more closely matches the accumulation period of two years and yet is long enough to spread the impact of the cost in a logical way. Walker direct testimony at 10 and surrebuttal testimony at 5.

Watkins proposed a five-year amortization period. He testified that considering the fact that the $25.618 million was collected from ratepayers in a manner inconsistent with the then existing statute, a five-year amortization is more equitable to ratepayers and still adheres to the stipulation. He further testified that if it were more than three years until SCE&G's next rate case, ratepayers would, under the Company's proposal, return more money to the Company than they paid improperly the first time. The effect of the Consumer Advocate's adjustment would be to reduce the

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[7] S.C. Code Ann. § 58-27-865 (Supp. 2003)

Company's pro forma O&M expenses by $3,179,000 (retail). Tr. Vbol. 3 at 960and Hearing Exhibit 23, Schedule 11.

The Commission Staff agreed with the amortization period proposed by the Company. Direct testimony of Scott.

The Commission agrees with the Consumer Advocate that under these circumstances, a five-year amortization period strikes a more equitable balance for ratepayers and the Company (Watkins surrebuttal testimony at 8) and that, therefore, is reasonable and does not represent a departure from the general principle to reasonably match accumulation and amortization periods as mentioned by the Company's witness Walker. In ruling this way, we also recognize thatratepayers might end up paying more than was improperly collected from them.

FUTURE TURBINE EXPENSES AND INVESTMENTS (ADJUSTMENT NO. 5) The Company has proposed to annualize over eight years $67.7 million of projected maintenance of certain of its generation plant turbines. Since these expenses will be incurred between 2005 and 2012 (Tr. Vol. 3 at 961), the Company stated that it would compare the actual costs incurred for turbine maintenance O&M each year to the expense level allowed in this case, and book any over or under collections to regulatory asset or liability accounts subject to further orders of the Commission. The effect of the proposed adjustment is to increase SCE&G's expenses by $5,412,193. Walker direct testimony at 11.

In his testimony, Mr. Watkins urged us to reject this proposal for the following reasons. (1) The costs are not known and measurable but merely forecasts; (2) the investments will not be used and useful until well into the future; and (3) the proposal represents a double collection of investments costs because the Company is requesting a return on (cost of capital) and return of (depreciation) its current investment in turbines as well as to collect today from the ratepayers future capitalized turbine refurbishments costs. The effect of Mr. Watkins' adjustment would be to reduce the Company's pro forma O&M expenses by $5,038,000 on retail electric basis. Tr. Vol. 3 at 961-962and Schedule 12, Hearing Exhibit 23.

Mr. Smith, testifying on behalf of the Navy, recommended using only five years of maintenance rather than the eight proposed by SCE&G. He represented that the period 2005 through 2009 included substantial maintenance at both Urquhart and Jasper and thus were fairly representative of high and low years and that the estimates of any future maintenance might be less reliable. Additionally, he observed that this was a novel proposal and as such should be subject to review in SCE&G's next rate case which, in his opinion, is more likely to happen within five as opposed to eight years. He further recommended that SCE&G report to the Commission on its actual versus projected expenditures and that any overcollected balance at the end of the five-year "trial" period be refunded to ratepayers. Tr. Vol. 4 at 1186. As a result of his recommendation, retail electric expense proposed by SCE&G would be reduced by $2,658,273. *Id.*, at 1187.

A somewhat similar approach was presented by the Commission Staff witness Watts in his direct testimony. Having admitted that these activities will result in additional expenses, he, like the Navy witness Smith, however recognized that there was more uncertainty associated with projections in the later part of the proposed eight-year cycle. Therefore, he recommended using an average of the initial four years with booking of the difference between actual costs and the level allowed in the rates. In addition, he recommended that the Company provide a report of these booked amounts at the end of the three years in order to allow the Commission to review the results for any further action it might find appropriate. Tr. Vol. 4 at 1374. The Staff backtracked from this position in the stipulation with the Company. In paragraph 9 of the stipulation, the parties agreed to the Company's proposal to annualize turbine maintenance expenses over an eight-year period as outlined in the Company witness Walker's direct testimony, provided, however, that the Company will file a report concerning the results of this mechanism reflecting data as of the end of calendar year 2007 for Staff review. The parties also agreed that the Company will accrue interest on the balance of any accrued liability resulting from this mechanism at the overall rate of return approved in this proceeding.

Mr. Marsh presented rebuttal testimony on this issue on behalf of the Company. He first disputed Mr. Watkins' assertion that these maintenance costs were "capital investments" and that the Company's proposal would result in a double collection of investments costs. In support, he referred to FERC Uniform System of Accounts, as adopted by this Commission, under which refurbishments costs can be capitalized only if the asset is returned to "like new" condition. He stated that costs incurred to maintain the operation of equipment must be classified as maintenance expense, which is not a capital expenditure and that turbine maintenance costs have been always treated as an O&M expense by this Commission. He further stated that these costs cannot be reflected in depreciation expense nor can the Company earn any return on them as it would on a capital investment, thus disputing that part of Mr. Watkins' testimony where he suggests that the Company attempts to overcollect. Tr. Vol. 5 at 1600-1601. Mr. Marsh further asserted that these costs were known and measurable because (1) the fact that the maintenance will be required is a fully known engineering certainty and (2) costs for turbines and generators at the new Jasper and Urquhart units are measurable based on the manufacturer's maintenance specifications. In addition, Mr. Marsh testified that the manufacturer offered a fixed-price contract for the maintenance of the five units at Urquhart and Jasper plants but that the Company rejected the proposal for this "turn-key" contract because its consultations with the manufacturer showed that if the Company itself were to perform or subcontract for important parts of the work and rely on the manufacturer only for those things that required the manufacturer's special expertise, the pro forma adjustment as proposed by the Company in this proceeding was more economical. Tr. Vol. 5 at 1602. Mr. Marsh, however, did not present any evidentiary support for his assertion. Mr. Marsh did not provide any rebuttal testimony with respect to the recommendations of Navy witness Smith and the direct testimony of Staff witness Watts.

With respect to Mr. Watkins' concerns that the Company may be overcollecting, we find that, for reasons espoused in Mr. Marsh rebuttal testimony, we agree that the expense in question is not a capital investment, but rather an O&M expense. Mr. Watkins did not provide any further discussion of this issue.

On the other hand, the portion of Mr. Marsh's testimony where he suggests that the Company's proposed treatment is more economical than the turn-key offer by the manufacturer may be interesting, but unfortunately, is of no evidentiary value. The Company did not provide any analysis of the alleged savings or information regarding its negotiations (if any) with the manufacturer regarding the pricing of the turn-key offer. Moreover, Mr. Marsh provided no information as to the proposed payment schedules under this contract, which item would or would not be covered under the contract, etc. Therefore, we cannot take this portion of his testimony into account in our ruling.

We are left with the fact that (1) these costs were not incurred in the test year and (2) their known and measurable attributes are questionable. Both witnesses for Staff and Navy also expressed concerns that the costs were estimated and that these estimates are likely to be less reliable the longer the period into which they are projected. They both recommended using either an average of the initial four years (Staff) or the actual initial five years of projected expenses (Navy). Both parties also recommended a rather similar reporting mechanism whereby the Commission could compare after certain time actual maintenance expenses incurred to the charges collected for that purpose from ratepayers. Although Staff and Navy proposals appear convincing and attractive, they do not represent a sound regulatory practice and, therefore, are rejected.

What the Company is requesting in this case is to collect today for expenses it expects to incur up to eight years in the future. As such, SCE&G would have access to these funds for up to eight years and accrue interest during this period of time. Moreover, the Company's proposal does not recognize time value of money. As we already observed, the proposed amounts are estimates and, as such, their known and measurable attributes are questionable. Therefore, we have no choice but to agree with the Consumer Advocate and to reject the adjustment in its entirety. In addition, we observe that Mr. Smith proposes to disallow NERC compliance costs (Adjustment No. 13c) for the same reasons as the ones he listed in his recommendations regarding the turbine maintenance costs although, based on essentially same reasons, he allowed the first five years of the projected maintenance costs. For that reason, the Consumer Advocate's recommendation appears as more consistent with the theory advanced for the Adjustment No. 13c.

AMMONIA COSTS (SELECTIVE CATALYTIC REACTOR O&M) (ADJUSTMENT NO.6)

The Company proposed to increase O&M expenses by $1,523,968 for costs associated with the use of ammonia in three new selective catalytic reactor units (SCR) installed at Wateree and Williams stations. This equipment has been required by State and Federal air quality regulations to reduce NOx emissions at those plants. One of those units was placed in service during the test period, and the other two after the test year closed. The adjustment reflects annualized O&M expense related to the operation of this equipment. The effect of this adjustment is to increase test year expenses by $1,523,968. Walker direct testimony at 12.

While Ms. Walker used the cost of ammonia as of March 2004, Mr. Watkins adjusted her amount to reflect the actual June cost of ammonia. Watkins Schedule 13 (Hearing Exhibit No. 23) shows that the effect of his adjustment is to increase the Company's pro forma O&M expenses by $17,000 on the retail basis.

In its direct testimony, Staff annualized actual ammonia expenses for this year's four-month ozone season over five months to reflect the length of the future ozone seasons.[8/] The Staff's adjustment would reduce ammonia expenses by $1,152,549 on a total electric basis and $1,080,000 on retail electric basis. Tr. Vol. 4 at 1295 and Audit Exhibit A-1, page 2 of 12 (Hearing Exhibit 33).

8/ Staff witness Scott testified that the ozone season for the first year was from May 31, 2003 to September 30, 2003. Thereafter the ozone season will be from May 1 to September 30. Direct testimony of Scott at 11.

The difference between the Company's and the Staff's positions seems to be resolved by the stipulation between these two parties. Since this adjustment is not specifically addressed in the stipulation, it seems to fall under paragraph 15 of the stipulation where the parties "agree that all other accounting and pro forma adjustments set forth by the Company and the adjustments as outlined in the PSC Staff's Testimony are fair and reasonable and have been agreed to by the Parties... ." We understand this to mean that the Company accepted the Staff reduction, provided, however that we accept the entire stipulation. *See also*, rebuttal testimony of Company witness Walker where she first asserts that since the first "ozone season" for these plants occurred after the close of the test year, it is appropriate to annualize the Company's experience during the initial months of the operations and thus to reflect current ammonia prices. She then proceeds to add that "[t]his issue would be resolved by acceptance of the stipulation." Walker rebuttal testimony at 6. Since the Commission is not accepting the stipulation in its entirety, we understand that the issue is still opened for the Commission's resolution.

None of the parties provided any further discussion regarding either the significance of the ozone season or any other underlying ratemaking theories regarding this issue.

It has been a long-standing practice of this Commission to annualize, for ratemaking purposes, the most recent data available. We agree with the Company that since the first ozone season for the plants in question occurred after the close of the test year, it is appropriate to annualize the Company's actual experience during the initial months of operations and thus to reflect the current ammonia prices. We further adopt Mr. Watkins' recommendation to reflect actual ammonia costs through June and thus to increase the Company's pro forma O&M expense by $17,000 on retail basis. While we appreciate the effort by Staff to reconcile the first, shorter season with the length of future ozone seasons, we believe that the Staff did not provide us with sufficient ratemaking principles for us to adopt its recommendation as presented in the direct testimony of Staff witness Scott.

WAGES, BENEFITS AND PAYROLL TAXES (ADJUSTMENT NO. 7)

In adjustment No. 7, the Company annualizes salary expense at the end of the test year based on salary levels in effect in March of 2004. Corresponding adjustments have been made in payroll taxes and certain employee benefit costs. The effect of this annualization is to increase SCE&G's O&M expenses by $6,511,153 and taxes other than income taxes by $461,805. Direct testimony of Walker at 12.

In her direct testimony, Staff witness Scott testified that Staff agreed with the Company on the basic wage and employee benefits increase of $6,511,153 on a total electric company basis. The Staff's adjustment to other taxes removed payroll taxes that had been computed on amounts above the FICA base. The Staff's computation of other taxes amounted to $421,822 on a total electric company basis. The Staff's Utilities Department determined the allocation to retail electric operations to be an increase to other taxes of $405,000. Tr. Vol. 4 at 1295-1296. In the stipulation between the Company and the Staff, the parties agreed in paragraph 13 of the stipulation that

> the Company's retail electric test year expenses be reduced for determining the revenue requirement in this case by $4,168,000 which represents the portion of executive compensation attributable to SCE&G electric operations related to the increase in salary and the incremental compensation paid to the five (5) Company officers listed in SCANA's Proxy Statement.

The Consumer Advocate witness Watkins deferred to Staff's audit to verify the reasonableness of using March payroll but made an adjustment to the Company's pro forma payroll and payroll tax amounts related to test year officers and employee bonuses. He testified that during the test year, the Company paid $4,938,540 in electric employee bonuses, and $6,549,083 in electric-related executive bonuses. Tr. Vol. 3 at 963. He recommended a 50/50 sharing of these cash bonuses between shareholders and ratepayers. The effect of his adjustment is to reduce SCE&G's pro forma O&M expenses by $5,513,000 on electric retail basis and reduce payroll taxes by $422,000. Id. at 964 and Watkins Schedule 14, Hearing Exhibit 23. Based on the Company's responses to Staff Data Request Nos. 1-77 and 1-90 (Hearing Exhibit No. 25), Mr. Watkins concluded that both employee and executive bonuses are based primarily in meeting or exceeding profitability goals and enhancing shareholder value. He opined that bonuses due to higher than expected profit levels should be paid out of profits, and not borne by captive ratepayers. Tr. Vol. 3 at 964. Witnesses for Navy and SCEUC did not address this issue.

On rebuttal, the Company witness Walker alluded to the stipulation of settlement as a compromise proposal to reduce the executive compensation included in rates by $4.2 million and further stated that should the stipulation be not accepted by the Commission, the Company would return to its basic position that the full amount of the compensation paid during the test year was a valid, recurring expense of utility operations and should be recovered through rates. Walker rebuttal testimony at 16 - 17. In support of its position, the Company offered a statement that its compensation packages are set annually based on surveys of market compensation in similarly situated companies and the Company's target and philosophy is to compensate employees and officers at the mid-point of the market. Ms. Walker then stated that "we are neither the highest or the lowest paying company, all factors considered, in our industry and region." *Id.*

In our view, the record does not support the Company's request for the full amount of the employee and executive bonuses. Based on the Company's responses to Staff Data Request Nos. 1-77 and 1-90, we agree with Mr. Watkins that both employee and executive bonuses are based primarily in meeting or exceeding profitability goals and enhancing shareholder value and that, therefore, bonuses due to higher than expected profit levels should be paid out with profits, and not borne by captive ratepayers. *See, e.g.,* with respect to employee bonuses

> SCANA's 2003 Employee Bonus Incentive Plan was based on the achievement of business unit strategic goals (50%), SCANA earnings per share (25%) and subsidiary earnings per share (25%) or SCANA earnings per share for SCANA Services employees.

With respect to executive bonuses, the Company stated, *inter alia* that

> SCANA's executive compensation program is designed to support <u>SCANA's overall objective of creating shareholder value</u> by
>
> ...
>
> Placing a substantial portion of pay for senior executives "at-risk" and <u>aligning the interests of executives with the long-term interests of shareholders</u> through equity based compensation; and
>
> Balancing elements of the compensation program to reflect SCANA's financial, customer-oriented and strategic goals.
> (Emphasis added.)
>
> Tr. Vol. 3 at 963-964 and Hearing Exhibit No. 25.

The Company did not provide any evidence as to how the goals of increased profit and enhancing the shareholder value directly benefit its captive ratepayers and, if they do, to what degree. Likewise, the record before us contains no evidence to support the Company's assertion that it is "neither the highest or lowest paying company, all factors considered, in the country or region." Walker rebuttal testimony at 17. The Company did not submit any evidence on its surveys of market compensation of similarly situated companies nor did it elaborate in any form on what it meant by "all factors considered."

As to the Staff's original position to disallow $405,000 on retail basis in what was paid above FICA, Staff did not elaborate on its reasons for removing payroll taxes computed on amounts above the FICA base and no other party addressed this specific issue. With respect to the Staff and the Company's stipulation to reduce test year expenses by $4,168,000 as described above, this reduction in revenue requirements was not addressed in the Staff direct testimony and the stipulation did not provide any discussion and evidence supporting the reduction. Nor does the stipulation address the question whether or not the Staff abandoned its position expressed in its direct testimony regarding the reduction of approximately $400,000 in taxes other than income taxes due to the amounts above the FICA base. Therefore, not only that we do not fully understand what the Staff's position was at the close of the case, but the record before us does not contain any evidence as to as to the $4.1 million reduction. We further understand that if we were not to accept the entire stipulation, the Company would revert to its initial request for a full award of bonuses. Since we are not accepting the entire stipulation and since the stipulated amount of $4.1 million is not supported by any evidence in the record, we have to reject it. Therefore, we could deny the Company's entire request with respect to employee and executive bonuses because the Company did not carry its burden of proof.

However, Mr. Watkins on behalf of the Consumer Advocate presented a reasonable approach which we, in our discretion, hereby adopt. The evidence before us shows that the bonuses in question are primarily based in meeting or exceeding profitability goals and enhancing shareholder value. After Mr. Watkins observed that bonuses due to higher than expected profit levels should be paid with profits, he, however, recognized that "increased profitability can and does come, in part, from increased efficiency, which will benefit ratepayers in the long run." Therefore he recommended a 50/50 sharing of the cash bonuses between shareholders and ratepayers. Tr. Vol. 3 at 964. Since, as we stated above, the Company did not carry its burden of proof with respect to the recovery of the entire amount requested, we feel that Mr. Watkins' proposed adjustment strikes a reasonable balance between shareholders' interests in which bonuses are profit-driven and ratepayers' interests which reflect increased efficiencies.

HEALTH CARE COSTS (ADJUSTMENT NO. 8c)

In developing the health care cost adjustment, the Company annualized the alleged increased cost of employee health care benefit expense in the first quarter of 2004 as compared to the test year. The effect of this adjustment is to increase expenses by $1,043,702. Walker, Direct Testimony at 13. Navy, SCEUC and Staff did not address this issue.

According to uncontroverted testimony of the Consumer Advocate witness Watkins, the actual test year health care costs for SCE&G were $27,832,606 but the Company's proposed normalized or going level amount is $30,161,988, resulting into an increase of actual test year amounts by 8.4%. Tr. Vol. 3 at 965. Mr. Watkins noted in his direct testimony that in the three months of January, February and March used by the Company to adjust the actual test year expense, the March 2004 expense of $4,032,983 was abnormally high and the February expense of $1,229,560 was abnormally low. *Id.* He further testified that since test year health care expenses fluctuated significantly, it could be reasoned that no adjustment was necessary since there was no clear upward trend in the Company's health care expenses during the test year. Admitting, however, that there is a general consensus that health care costs are rising faster than inflation, he adjusted actual test year amounts to reflect higher health care costs. To do so, he used the data for the most recent annual increase (inflation) in health care costs for the first half of 2003 to the first half of 2004 in the Southern United States as reported by the U.S. Department of Labor, Bureau of Labor Statistics. The current health care inflation rates are as follows:

3.9% for all Southern Urban Consumers;
4.1% for Southern Consumers in metropolitan areas of 50,000 - 1,500,000 population; and
3.2% for Southern consumers in metropolitan areas with less than 50,000 population.

Mr. Watkins then selected the highest inflation rate, *i.e.,* 4.1% and applied this rate to actual test year health care costs. His adjustment resulted in a decrease to the Company's pro forma O&M expenses of $508,00 on electric retail basis. Tr. Vol. 966 and Schedule 15 (Hearing Exhibit No. 23).

In an effort to rebut the Consumer Advocate's position, the Company recomputed the annualization amount by updating it to reflect actual costs through August 2004 (as opposed to January to March period utilized in the application) and demonstrated that annualizing the January-August period resulted in an increase in total health care expenses to $30,182,204 as opposed to $30,161,988 for the January-March period. Based on this comparison, the Company argued that its pro forma health care adjustment was fully substantiated.

The Commission agrees with the Consumer Advocate's position for the following reasons.

A historical test year concept has long been used in South Carolina for ratemaking purposes. Adjustments to actual test year expenses are considered when there is reasonable evidence that test year expenses are not reflective of current costs. For example, if employee health care benefits are provided by an outside insurance policy and the premium rates increase by a known and measurable amount, an adjustment to reflect the current insurance premium may be warranted. However, such is not the case with SCE&G as the Company is self insured for health care benefits. Transcript at XXX. As demonstrated by Mr. Watkins, SCE&G's actual monthly health care costs fluctuated widely during the test year from a low of $691,777 in December 2003 to a high of $4,032,983 in March 2004. Tr. Vol. 3 at 965. Due to this month to month volatility, which may or may not be random, an adjustment based on a partial year (whether it be thee months or eight months) which is then annualized is not appropriate in this instance, particularly in light of the exceptionally low expense incurred in December (which is outside of the partial year period considered). However, the Commission agrees with Mr. Watkins that there is a consensus that health care costs are increasing faster than prices generally, and therefore accepts and adopts the Consumer Advocate's adjustment to health care costs.

FUTURE TRANSMISSION INVESTMENT AND EXPENSES (ADJUSTMENT No. 13c)

This adjustment increases General Plant in Service and O&M expense for costs associated with compliance with new NERC standards related to increasing electric transmission system reliability. Specifically, the Company estimates these future investment costs to include $240,000 for software, $481,000 for electronic equipment, $370,000 in future external construction costs, and

$218,000 in allocated future internal labor. The total projected capitalized investment, *i.e.,* the plant in service, totals $1,309,000. In addition, the Company anticipates that it will hire eight new employees at an average salary of $80,000 per year, and incur additional $180,000 per year in consultant and contractor costs. These forecasted expenses (including a provision for employee benefits) total $1,050,000 per year. Finally, the adjustment increases the amortization expense by $48,000 to the total amount of the adjustment of $2,407,000. Walker direct testimony at 15 and Tr. Vol. 3 at 967.

Witnesses for both the Navy and the Consumer Advocate concluded that the total adjustment should be removed. SCEUC and the Staff testimony did not address this adjustment. Mr. Smith on behalf of Navy opined that the adjustment did not meet the known and measurable standard. As shown on Mr. Smith's Schedule 5, (Hearing Exhibit 29) he would reduce SCE&G's proposed pro forma addition to test year expense by $870,000. Tr. Vol. 4 at 1184. Mr. Watkins, drawing a parallel to the Company's proposed projected future investment in turbine costs (Adjustment No. 5), stated that the investment amounts were not in service and that the proposal reflected estimates or forecasted amounts for future costs. The effect of Mr. Watkins' adjustment is to reduce the pro forma plant in service by $1,257,00 (retail), reduce depreciation reserve by $46,000 (retail), and reduce O&M expenses by $988,000 (retail) to the total of $2,291,000 (retail). Tr. Vol. 3 at 967 and Schedule 16, Hearing Exhibit 23.

On rebuttal, the Company did not introduce any new evidence. For essentially the same reasons as we adopted with regard to Adjustment No. 5 (turbine maintenance expense), we reject the Company's proposed adjustment in its entirety.

JASPER GENERATION PROJECT ADJUSTMENTS (ADJUSTMENT NO. 17)

This adjustment, consisting of four parts, relates to the Jasper County generation project (Jasper plant) having been placed in service on May 1, 2004. It updates Plant in Service, Depreciation Expense, O&M Expenses (including firm fixed capacity charges) and Property Taxes due to the addition of the Jasper Plant.

Plant in Service Adjustment

It is apparent from the record before us that the Commission was not sufficiently informed about the nature of the NCEMC sales during the siting case and the 2002 rate case.[9] The fact that the sale may be characterized both as firm or recallable (or an opportunity sale), is clearly demonstrative of this. The unclear nature of the sales complicates, as Dr. Dismukes aptly demonstrated, the accurate determination of the Company's actual reserve margins. At the same time, it appears to us that we cannot make a prudency determination with respect to the Jasper plant without knowing the actual reserve margins. For these reasons alone, Dr. Dismukes' argument that the additional capacity (48% of the Jasper plant) is for now and some foreseeable future not used and useful and should be removed, along with its corresponding NCEMC revenues for retail ratemaking purposes (Dismukes surrebuttal testimony at 27) is rather persuasive.

On the other hand, we are mindful of the fact that the Commission allowed the plant to be constructed in its proposed configuration in the siting case, albeit reserving its judgment as to the

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[9] The Commission takes a particular note of the fact that the existence of the second (100 MW) NCEMC contract was revealed to the Commission only during the cross examination of two Company witnesses by counsel for the Consumer Advocate and SCEUC during the 2002 rate case and that, for the purposes of the current proceeding, the Company considered these admissions as a sufficient information. *See,* response to Columbia's data request No. XXXX.

ratemaking treatment of the investment in the plant. We are also aware that the Commission already allowed 58% of the cost of the Jasper plant as CWIP in the 2002 rate proceeding, which amount will now be transferred into the rate base.

Having carefully considered the arguments of both Columbia Energy and SCE&G, as well as the entire history of all the proceedings related to the Jasper plant, we will reluctantly allow the remaining portion of the Jasper plant into the retail rates because we feel is too far along into the construction and operation of the plant to reverse course and disallow the remaining portion of the Jasper plant, although we recognize that we have the authority to do so.

We feel very strongly that the Commission should not be put again into the same situation as the one we face in this case in the future. Having considered the well reasoned argument for creating a competitive bidding requirements for South Carolina investor owned utilities, and viewing these arguments against the regulatory history of the Jasper plant, we see the requirement of competitive bidding as a safeguard against what may appear as self-serving and non-transparent utility decision making processes which the Commission is merely asked to rubber stamp. Therefore, we will initiate such rule-making proceeding in a separate order.

We disagree with the assertions by SCE&G and the Commission Staff in the part of paragraph 4 of their stipulation which states that

> [t]he parties stipulate and agree that the Commission's order approving the siting of the Jasper plant (Order No. 2002-19) determined that the plant is properly sized at 875 MW when the 250 MW opportunity sale from system resources to North Carolina membership Cooperation is taken into account, and further that the Commission's Order in the last SCE&G electric rate proceeding (Order No. 2003-38) properly determined that the plant was used and useful for utility purposes in its 875 MW configuration.

Although there is no dispute as to what the Commission stated in those orders, the issue of the additional 100 MW "surplus" was not raised in those dockets.

Fixed Pipeline Capacity Charges Adjustment

SCE&G proposes to remove these charges from the fuel adjustment clause to allow recovery through base rates. The amount of the fixed pipeline capacity charges SCE&G must pay for the provision of interstate gas service to the Jasper facility is $15,292,800 per year. These charges are presently included in the Company's annual fuel forecast and are currently being recovered through the fuel adjustment clause. The Company is proposing to remove the retail portion of this amount, which, according to the Company's witness Walker is $10,922,000, from the fuel adjustment clause calculations and include them in calculating base rates. In the initial period the rates are in effect, this would reduce the fuel factor computed in Docket No. 2004-02-E by $0.00057/kwh. To ensure that there is no over or under recovery of these charges in future years, the Company proposes to flow any positive or negative difference between the amount reflected in base rates and the actual charges for the fixed capacity charges through the fuel adjustment clause. Walker direct testimony at 18 - 19.

The Commission Staff did not address this particular adjustment in its direct testimony but in paragraph 5 of the stipulation it agreed with the Company that the treatment of fixed pipeline capacity charges, as requested by the Company, was appropriate. Witnesses for Navy and SCEUC did not address the issue.

Consumer Advocate witness Watkins notes that the amount of Jasper's fixed capacity charges is in dispute and is being contested in another pending proceeding before the Commission in Docket

No. 2004-126-E. Even though his testimony in Docket No. 2004-126-E was filed under seal due to SCE&G's assertions that it contains competitively sensitive information affecting its unregulated affiliates, he made a general statement in the current docket that in his sealed testimony he concluded that the amount of fixed pipeline capacity charges ($15.293 million) was grossly excessive. Therefore, he recommended that the Commission not include Jasper's fixed gas supply costs in base rates until the matter in Docket No. 2004-126-E is resolved. Finally, he observed that the Company is currently collecting the full $15.293 million in fuel clause revenues and will continue to do so until we make a finding in Docket No. 2004-126-E. The result of his recommendation is to reduce SCE&G's pro forma O&M expense by $14,398,000 (retail). Watkins direct testimony at 58 - 59 and Watkins Schedule 17, Hearing Exhibit No. 23. Rebutting Mr. Watkins' testimony, the Company witness Walker stated that this Commission has considered arguments concerning the Jasper fixed capacity charges in the Company's annual fuel clause hearing in Docket No. 2004-2-E, and approved them. She then reiterated that should the Commission in any way revise its decision concerning the recovery of any of these costs, the effect of such decision would be immediately reflected in the Company's fuel clause calculations and customers would get a full benefit of that decision. Walker, rebuttal testimony at 10.

We agree with the Consumer Advocate and will not allow the amount of fixed pipeline capacity charges for the Jasper plant into base rates until the issues in Docket No. 2004-126-E are resolved. We find that the Company is incorrect in stating that we have considered and approved the Jasper fixed capacity charges in Docket No. 2004-2-E. The open record in that proceeding clearly shows that the entire issue of these charges was presented to the Commission and the parties in such an untimely manner that neither the Commission nor the parties could meaningfully consider the relevant issues. It was precisely for this reason that we established a separate docket to fully consider these issues and that in Docket No. 2004-2-E we approved Jasper fixed capacity charges conditionally until our ruling in the newly established Docket No. 2004-126-E. We did so because we were faced with a difficult situation where on one hand, the plant was already running and needed to rely on the contracted gas supply and, on the other hand, were deprived of the opportunity to consider the reasonableness of both the volume of the contracted for capacity and the charges for that capacity.

We further note that in the 2002 rate proceeding, the Company stated that it intended in the future to include these charges into the base rates and that we allowed the same treatment for the fixed pipeline capacity charges for Urquhart natural gas units. Order No. 2003-38 at 25-26. In April of 2004, we included these charges into the fuel factor <u>upon the Company's request</u>. The Company filed the current rate change application on June 30 of 2004 asking us to reverse the very treatment of these charges that it requested of us just a few months ago. In support of its position, the Company argues that should we adjust the fixed capacity charges in Docket No. 2004-126-E, any resulting difference could be resolved by floating it through the fuel charge. We believe that a more appropriate and orderly regulatory disposition of this issue is to first resolve all issues in Docket No. 2004-126-E. Because of the gravity and the magnitude of the issues in Docket No. 2004-126-E, we will not accord a rate base treatment to the fixed capacity charges for the Jasper plant at this time.

There is yet another reason for us leaving these charges in the fuel clause. The question was raised by counsel for Columbia Energy and the Consumer Advocate during the cross and recross examination of the Company witness Walker concerning how the Company got from $15.3 million in fixed pipeline capacity charges that are presently recovered through the fuel adjustment clause to the retail portion of $10.9 million which the Company desires to put now into base rates. *E.g.,* Tr. Vol. 3 at 759. Counsel for Columbia Energy questioned whether or not there was a different wholesale/retail allocation factor for this item as compared to other items subject to such allocations. While referring the bulk of these questions to the Company witness Hendrix, Ms. Walker nevertheless stated that there were certain formulae and procedures in place in the fuel clause to adjust the numbers, without providing any specifics. Tr. Vol. 3 at 823-824. Company witness Hendrix shed some light on the issue by stating on cross-examination that $15.3 million was the annual gas firm transportation charge for the Jasper plant out of which the Company backs out the revenue received from NCEMC sale, which then yields a number of approximately $11.7 million to which then the Company applies the proper wholesale/retail allocation factor of about 93% to come up with $10.9 million. Although we have no reason to doubt Mr. Hendrix's explanation, we feel very strongly that the Company should have provided this explanation in its application and prefiled testimony as opposed to it being brought to us on cross-examination of its witnesses. Other than these verbal explanations, there still is no evidence before us as to how the formula mentioned by Ms. Walker works. In particular, it is not clear from these verbal explanations how the NCEMC charges were arrived at or how the Company reconciles the $15.3 million that it, by its own admission, charges through the fuel clause with the NCEMC deduction mentioned by Mr. Hendrix. It is the Company who requested earlier this year that the charges in question be put into fuel clause. It is the Company who bears the burden of proof to show why we should move the charges into base rates and whether the amount to be put into the base rates is the proper one and it is the Company who chose not to elaborate on these issues in its application and prefiled testimony. For these reasons we believe that the treatment of fixed pipeline capacity charges should not change until we have a full and meaningful opportunity to address them in Docket No. 2004-126-E.

FOSSIL FUEL INVENTORIES (ADJUSTMENT NO. 19)

The Company's original request to increase fossil fuel inventory by $23.340 million was amended on August 27, 2004 when SCE&G filed a correction to its Adjustment No. 19, revising its October 2003 actual coal inventory amount and also revising its requested increase to $13.257 million and the total requested fuel inventory to $40.635 million. With this revision, the retail jurisdictional increase requested by the Company is $12.339 million and brings the retail fossil fuel inventory that SCE&G proposes to $37.823 million. Tr. Vol. 4 at 1172.

Regardless of this correction, the Company's request still reflects forecasted coal prices and desired inventory tonnages. *See, e.g.,* Tr. Vol. 3 at 970. Witnesses for both the Consumer Advocate and the Navy adjusted the Company's request to reflect actual average test year levels. Mr. Watkins testified that since coal inventories were part of materials and supplies which are included in the rate base, the Company should not be allowed to earn a return on inventory it does not have. *Id.*, at 970. Likewise, the Navy witness Smith also testified that it was appropriate and more representative of normal experience to utilize an average balance for determining the rate base amount. Tr. Vol. 4 at 1172. Mr. Smith also noted that a 12-month average was used to determine SCE&G' s materials and supplies balance, which includes fossil fuel inventories, in its prior rate cases. *Id.*

On rebuttal, Company witness Walker introduced a five-year average inventory for the years 1999-2003 of 733,167 tons and stated that this tonnage was more than the target inventory requested by the Company in its Application, as modified.

We find the assertions submitted by the Company in its rebuttal testimony on this issue as immaterial inasmuch as it does not change the fact that the Company is attempting to collect in rates for inventories they do not have. Therefore, we find testimony of Mr. Watkins and Mr. Smith convincing and hereby adopt their recommendation to utilize actual average balance for determining the rate base amount as opposed to adopting desired inventories based on forecasted coal prices.

GRIDSOUTH RTO COSTS (ADJUSTMENT NO. 20)

The Company seeks to amortize costs it allegedly incurred to form a new Regional Transmission Organization (RTO) to be called GridSouth. The Company claims that its investment in the project is $14,095,964 as of March 31, 2004, including carrying costs as permitted by FERC order. The Company is proposing to amortize this investment over five years with a resulting increase in annual O&M expense of $2,819,193. The Company also proposes to include in rate base $7,047,982 representing half the amount of investment which will be reflected on the Company's books during the five-year amortization period requested.

The rebuttal testimony of Company witness Dr. Wright recounts a history of the actions of FERC as it pertains to the creation and ultimate suspension/termination of GridSouth. For purposes of this Order, the relevant facts are summarized as follows:

On December 20, 1999, FERC issued its order No. 2000 which required utilities regulated by that agency to file a plan to join or form a regional transmission organization (RTO) that would be operational by December 15, 2001, or provide an explanation as to why this could not be accomplished. As a result of that order, a number of utilities undertook complying efforts. SCE&G, Duke Power and Carolina Power & Light joined efforts to form a for-profit RTO under the name GridSouth. The companies made their GridSouth filing with FERC on October 16, 2000, and FERC gave conditional approval for the RTO in March, 2001. *Carolina Power & Light Co.,* 94 FERC ¶ 61,273 (March 14, 2001 Order). In this Order, FERC provisionally approved GridSouth as a for-profit RTO, operating in North and South Carolina. FERC also provisionally approved organizational documents under which the participating utilities would manage the formation and operation of GridSouth. The "provisional approval" indicated the fact that FERC was requiring that the original GridSouth documents be refiled with some changes to reflect the matters decided in the March 14, 2001, Order. Although FERC issued an Order provisionally accepting the formation of the RTO, there remained the question of the independence of the RTO from its founders. Pursuant to various notices from FERC, GridSouth represented that it would limit its spending prior to the seating of an independent board for the RTO, which never took place.

During the summer of 2001, a leadership change at FERC resulted in a dramatic change in that agency's RTO regulatory objectives. *See e.g. Regional Transmission Organizations, Order Initiating Mediation,* FERC ¶ 61,066 (2001). As a consequence of this change in policy, the formation of GridSouth no longer appeared consistent with FERC RTO objectives and, on June 18, 2002, the three participating utilities suspended this project.

The Company made an identical request to this Commission in its previous rate case (Docket No. 2002-223-E). We denied the request for the following reasons stated in Order No. 2003-38 at 16, 17: (a) most of the costs were incurred before the test year; (b) not much detail was provided by the Company as to the nature of the investment in the project; (c) the Company has not met its burden for cost recovery at this time; (d) staff concluded that since GridSouth was not operational during the test year, it should not have been considered used and useful during that time, although it might have been considered property held for future use; (e) the costs involved were imposed as a result of FERC mandates; (f) it is premature to allow recovery of GridSouth costs at the retail level at this time; and (g) the door should remain open on this issue, and that allowance of GridSouth costs should be deferred until such time as the Company can meet its burden of proof and/or until FERC rules on the allowance of the expenditures at the wholesale level. Order No. 2003-38 at 16-17.

Consumer Advocate witness Watkins, Navy witness Smith and SCEUC witness O'Donnell testified against allowing recovery of GridSouth in this proceeding. Staff witness Scott proposed to amortize the total amount invested by the Company over a five-year period excluding interest expense of $527,511. Staff rejected the Company's proposal to include the unamortized investment balance in rate base in order to share some of the GridSouth costs between ratepayers and stockholders. In the stipulation, Staff and the Company agreed on the treatment of GridSouth costs as proposed by the Company, excluding, however, the carrying costs.

Mr. Watkins relied on our ruling in the 2002 rate case and on his testimony in that case and, specifically, reiterated the 17 questions related to this issue in his 2002 testimony. Tr. Voil. 3 at 974-976. He testified that most of these questions remain unanswered today and that nothing has changed with respect to GridSouth since our 2002 ruling except for a statement by Company witness Lorick at pages 16 and 17 of his direct testimony that all assets of GridSouth have now been disposed of and there will be no future utilization of this vehicle for transmission or any other purposes. *Id.*, at 972.

Mr. O'Donnell testified that the primary purpose in the movement toward RTOs is to enhance the development of competitive wholesale power markets and he opined that an RTO with only three market participants would have done nothing to enhance the level of competition that already exists in the market. Tr. Vol. 4 at 1237.. He mentioned the fact that both North and South Carolina were beginning to experience transmission problems and demonstrated it by referring to the September 24, 2004 North Carolina filing by the load serving and investor-owned utilities serving that state that would establish an "RTO-lite" scenario in which a single entity would oversee a transmission planning for North Carolina. Given the fact that both Progress Energy and Duke Power serve both North and South Carolina, he expressed an opinion that a similar development in South Carolina was a distinct possibility. He also expressed his belief that the FERC will, within a foreseeable future, require some form of a transmission entity involving both North and South Carolina. Once that happens, the costs associated with GridSouth will again become a wholesale matter and SCE&G could seek recovery of such costs from the FERC. As a result, Mr. O'Donnell concluded that SCE&G's request to seek recovery of GridSouth expenses was premature at this point in time. *Id.*

Navy witness Smith opposed inclusion of these costs in rates for two reasons. First, he asserted that these costs were non-recurring and did not meet the traditional standards for deferred cost recovery which allow amortization of a non-recurring cost if the expense is the result of a non-recurring event that has a significant adverse impact on the utility's financial condition. In this connection, Mr. Smith observed that GridSouth costs do not rise to the level of materiality as they are less than one percent of SCE&G's operating revenues and less than 1/4 percent of total assets. Tr. Vol. 4 at 1169. He further testified that these non-recurring costs do not meet the "future benefit" standard in order to be properly amortized into rates. GridSouth start up costs and expenses may eventually meet this standard and be included in the FERC transmission tariff and allocated to the retail jurisdiction, but according to Mr. Smith, as of today, any possible future benefit to retail ratepayers is neither known nor measurable. *Id.* He also testified that these costs never provided plant, goods or services used and useful in providing retail electric service to SCE&G customers and thus fail the ratemaking standard of used and useful. *Id.*, at 1170. Mr. Smith's second ground for denying recovery of the GridSouth costs is jurisdictional in that SCE&G is seeking recovery from South Carolina PSC jurisdictional customers who did not create the circumstances that led to these costs. If and when FERC approves these costs and includes them in FERC's tariffs, it would then be reasonable to permit their allocation to the retail jurisdiction. Since no such finding has been made by the FERC, allowing recovery from retail customers is, according to Mr. Smith, premature. *Id.*, at 1170-1171. Finally, like Mr. Watkins, Mr. Smith observed that the same concerns the Commission had with respect to this issue in Docket No. 2002-223-E, are also applicable in the current case and should produce the same conclusions. *Id.*, at 1171.

Having reviewed Commission Order No. 2003-38 and the testimony on this issue in the current case, we agree with witnesses for the Consumer Advocate and Navy that the same factors that were applicable in Docket No. 2002-223-E continue to be applicable in the current case. The Company has not provided any testimony demonstrating a significant change in circumstances that would justify our departure from the position we took in the 2002 rate case. We also agree with Mr. O'Donnell and Mr. Smith that the request for the recovery of these costs is premature because future developments are likely to bring this issue again before the FERC for the potential approval and recovery through FERC tariffs and the subsequent South Carolina retail allocation.

CONTINUATION OF THE ACCELERATED DEPRECIATION OF THE COPE GENERATING STATION

In his direct testimony, the Company witness Marsh asked the Commission to extend until December 31, 2010, the period over which it would be able to apply the accelerated capital recovery mechanism originally approved by the Commission in Docket No. 1999-389-E, Order No. 1999-655. This order allows the Company, in its discretion, to accelerate depreciation of its Cope Generating Station when revenue and expense levels warrant. The mechanism would have expired on December 31, 2002, had it not been extended by the Commission in Order No. 2003-38 until December 31, 2005. Tr. Vol. 1 at 284. However, having reviewed the testimony of the Company's own depreciation witness Spanos on cross examination by the Consumer Advocate counsel (Tr. Vol. 2 at 660 - 667), we are now convinced that this accounting treatment does not comport with reasonable or proper ratemaking and accounting principles and as such, the continuation of the accelerated depreciation for the Cope Station as requested by the Company is denied.

STIPULATION

For the reasons set forth above in this Order, the Commission finds that the proposed Stipulation between the Staff and the Company is not in the public interest, and is therefore not approved